BEFORE THE PUBLIC UTILITIES COMMISSION
OF THE STATE OF CALIFORNIA

Order Instituting Rulemaking Regarding Policies, Procedures and Rules for Development of Distribution Resources Plans Pursuant to Public Utilities Code Section 769	Rulemaking 14-08-013 (Filed August 20, 2014)

COMMENTS OF ENPHASE ENERGY, INC. ON THE DRAFT DISTRIBUTION RESOURCE PLANS GUIDANCE ATTACHED TO THE ASSIGNED COMMISSIONER'S RULING RE DRAFT GUIDANCE FOR USE IN UTILITY AB 327 (2013) SECTION 769 DISTRIBUTION RESOURCE PLANS (CORRECTED)

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December 15, 2014

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I. INTRODUCTION

Enphase Energy, Inc. ("Enphase") appreciates this opportunity to comment on the draft guidance attached to the "Assigned Commissioner's Ruling Re Draft Guidance for Use in Utility AB 327 (2013) Section 769 Distribution Resource Plans" (the "DRP Draft Guidance"). Enphase applauds the Commission's work to enhance the ability of California's distribution systems to incorporate new means of providing energy, energy services and demand management, and as a result to enhance the reliability, cost-effectiveness and emissions profile of California's energy system.

II. RECOMMENDATIONS FOR A COST-EFFECTIVE AND INCREMENTAL APPROACH TO THE ROLL-OUT OF DISTRIBUTED ENERGY RESOURCES

Enphase offers the following recommendations to help ensure the Commission's success in achieving the fundamental objectives of the DRP proceeding, particularly in regards to streamlining and reducing the costs of the Distributed Energy Resource ("DER") interconnection process, as well as effectively managing the cost of the changing distribution system. Our recommendations are meant to foster an incremental approach to the roll-out of DERs, while first establishing a strong foundation for DER growth that relies heavily on harnessing existing systems. As a technical expert, Enphase is uniquely qualified in the DER market, having significant experience in States such as Hawaii in solving today's real-world reliability issues. Our work in Hawaii, which enables use of the existing, installed base to solve complex problems, is directly applicable to the modeling, validation, and locational value determinations needed for the DRP process.

Modeling and validation of the distribution system's capabilities, determining locational value, and explicitly recognizing the roles of DER aggregation and control systems are all key to the success of the Commission's efforts. Enphase believes three issues in particular deserve greater attention than the DRP Draft Guidance provides, in order to help: (a) simplify the DER roll-out process, (b) decrease costs, (c) increase the accuracy of locational value calculations, (d) improve the interconnection process, and (e) maximize ratepayer investment value.

(1) **Adequate Data, Modeling, Validation & Analyses.** Adequate data, modeling, validation and analyses are critical to the success of Phase 1. In order to adequately approximate the hosting capacity of existing circuits in investor-owned utilities' ("IOUs") distribution systems, appropriately value DERs, and avoid substantial and unnecessary expenditures, it is essential to ensure that power flow studies reflect the majority of IOUs' existing circuits by utilizing existing feeder level data that is critical to DER implementation. Furthermore, results from models must be "validated" through ongoing data collection. The use of historical data from the IOUs' existing installed base of DERs is crucial to determining model accuracy through validation testing and minimization of forecast error. California IOUs should be required to utilize historical data from their existing DER systems to achieve a greater level of modeling accuracy, as well as to upgrade DER systems to provide additional data, particularly in the event forecast error is unacceptably high. To enable the necessary functionality to collect new data, as well as to monitor and eventually control DER systems, Enphase recommends that the Commission also require remote upgrade capabilities for all new DER systems deployed. Through its experience in Hawaii in helping improve circuit level performance and reliability, Enphase believes remote upgrade capability is an important and critical feature to ensure grid resiliency as renewable saturation levels increase over time.

(2) **Recognition of Control Systems as DERs & Inclusion in the DER Pilots**. The ability of the distribution system to absorb DERs, as well as the value of those DERs, will substantially depend on (i) DER visibility to the distribution system operator and (ii) the degree to which DER provision of energy and energy services can be controlled (whether directly or, when DERs are aggregated, indirectly). DER sensor, communication, and management systems (collectively, "DER Control Systems"), independent of other DER elements or of distribution system operators, are critical to the costs and benefits of the increasing numbers of DERs, and should be included as a separate element of the Commission's DER definition. Due to the pivotal importance of DER Control Systems to the distribution systems' capacity to absorb DERs, as well as to DER reliability and cost, the value of differing DER Control Systems should be explicitly tested in the Commission's proposed first DER pilot.

(3) **Monitoring, Measurement & Control in New Smart Inverter Deployment.** Monitoring and measuring reactive power and voltage magnitude power flow variables is necessary for determining hosting capacity at the feeder level within an acceptable level of error. As envisioned by Rule 21, all smart inverters will have the ability to capture both voltage magnitude and reactive power flow variables in future generations. Building on the foundation established under Rule 21, it is important for the Commission to consider requiring new smart inverter technology in future DER systems, to allow data collection, monitoring and eventual control of power flow variables with these devices. These steps are necessary to ensure the visibility at the feeder level required to accurately approximate hosting capacity, as well as to improve locational value calculations and minimize costs—and these steps should be implemented during Phase 1 of the DER roll-out strategy.

Fortunately, existing DER systems with associated advanced control capabilities offer a substantial amount of data that can be used to validate Phase 1 data and modeling. This data can also serve to form the basis of a meaningful pilot to evaluate the role of DER Control Systems. While the Commission will need to address transactional and privacy issues associated with the collection and use of DER data, as well as management of existing contracts and revenue considerations associated with that data, those issues should be addressed in a separate track.

III. ADEQUATE DATA, MODELING, ANALYSES & VALIDATION ARE FUNDAMENTAL TO SUCCESS OF THE DER PROGRAM

Adequate data, modeling and analyses—and their proper validation—are critical to the success of Phase 1, and necessary to assess the hosting capacity of the existing distribution system and need for any upgrades, as well as to appropriately value DERs. The general approach to performance data acquisition and analyses suggested in the DRP Draft Guidance could easily lead the Commission and the IOUs, albeit with the best of intentions, to inefficient expenditures. The underestimation of existing distribution system capacity, overestimation of distribution system integration costs, and incorrect assessment of DER value under differing scenarios could all potentially lead to unnecessarily increased expense and avoidable reliability issues. Proper power flow studies, supported by an adequate representation of actual data, and validation of analyses are essential to providing the benefits the Commission seeks from DERs.

Recent study findings by Electric Power Research Institute ("EPRI"), the National Renewable Energy Laboratory ("NREL"), and Sandia National Laboratories ("Sandia"), including work undertaken in conjunction with the Commission, confirm that the hosting capacity of a distribution system cannot be accurately assessed through simple feeder attributes (such as minimum daily load, maximum daily load, and feeder length); detailed power flow modeling tailored to the nature of distribution systems and based on actual data is required.[1] The potential reductions in distribution system cost upgrades, recognition of DER value and resulting focused deployment of DER merit the a requirement that IOUs' power flow models are validated within a reasonable forecast error rate early in the DER vetting and implementation process. This can only be done by utilizing currently available data from existing DER systems with the potential need for upgrades to additional systems in IOU's networks that do not have remote upgrade capabilities.

[1] Broderick et al, "Time Series Power Flow Analysis for Distribution Connected PV Generation," Sandia Report SAND2013-0537 (Jan. 2013), available at http://energy.sandia.gov/wp/wp-content/gallery/uploads/SAND_Time-Series-Power-Flow-Analysis-for-Distribution-Connected-PV-Generation.pdf; see also Broderick et al, "Using Hosting Capacity Methodology to Develop Simplified Screens for New Solar PV Interconnections" (presentation at 6th International Conference on Integration of Renewables and DER in Kyoto, Japan) (Nov. 2014) (a copy of which is attached).

The DRP Draft Guidance recognizes that data, modeling and analyses are necessary for developing circuit level DER capacity maps and to provide a base case for DER penetration models in Phases 1 and 2a. However, the Guidance's Integration Capacity Analysis requirement is insufficient to achieve its intended result. Appropriate models, parameters and inputs are not contemplated in determining existing DER capacity; the Commission's only requirement in developing these base case distribution models appears to be that a dynamic modeling approach be used and that heuristic analyses should be avoided. A particularly important omission is consideration of modeling error, which could lend significant uncertainty to the applicability and effectiveness of the base model in determining optimal location and locational value for DER resources. Given the availability of substantial data, this presents an unnecessary risk.

Identification of optimal locations for DER and the determination of locational value should first be guided by an approximation of the operational attributes of a distribution network within an acceptable standard of error. While any power flow modeling based on actual data would be better than more simple assessments, the power flow models generally pervasive today fail to adequately capture the variables key to DER integration, particularly as demand response and distributed renewable generation levels increase. As one recent study noted, "[e]xisting linear active-power flow approximations are generally used to plan power systems," but "AC distribution power systems are governed by a system of non-linear nonconvex power flow equations."[2] The study concludes that "[e]xisting linear approximations fail to capture key power flow variables, including reactive power and voltage magnitudes,"[3]— the factors that are substantially responsible for determining maximum hosting capacity on any circuit for DER resources. As envisioned by Rule 21, all smart inverters will have the ability to capture both voltage magnitude and reactive power flow variables in future generations. The Commission, building on the foundation set in Rule 21, should ensure that these capabilities are utilized to reduce costs and ensure reliability, by requiring the use of this new smart inverter technology to collect data, monitor and eventually control power flow variables with these devices. As noted by Coffin & Van Hentenryck, "Power grids," including distribution systems, "now need to operate in more stochastic environments and under varying

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[2] Coffin & Van Hentenryck, "A Linear-Programming Approximation of AC Power Flows," INFORMS Journal on Computing (2014).
[3] Id.

operating conditions while still ensuring system reliability and security."[4] The data used for modeling, to meet minimum standards of sufficient accuracy, should be representative of distribution circuits; the use of a large sample population on relevant circuits, with adequate measurement standards and error reporting, must be required. DER systems that do not have the ability to collect and transmit data should be upgraded to provide a representative sample set of data, which is a necessary element of a sound foundation for modeling and resulting decision-making. Remote upgrade capability for DER systems should be mandatory for all new DER devices deployed to ensure that future data collection, system monitoring and control functionality needs are met as DER systems evolve and renewable saturations levels increase.

Once the base hosting capacity for DER resources is approximated using power flow modeling and historic DER data, a representative sample of circuits in a utility's distribution network must be tested to validate that the power flow model approximates the hosting capacity within a pre-determined standard of error. Error can be quantified by comparing predicted data versus measured data under real-world conditions, and models can be rectified accordingly, potentially necessitating augmented data as well.[5] Backtesting against measured historical data, which is available, is therefore essential to determining model accuracy and ensuring that future investments in the distribution system are both justified and efficient. By comparing model results, which rely on a power flow engine as well as the actual material quantities, to real-world measurements, modeling of the distribution systems and their hosting capacities can be substantially improved. This validation should save significant costs in avoided distribution upgrades as well as by providing an accurate recognition of DER value. It will also enhance the likelihood of success in achieving the Commission's objective of DER zones and a streamlined, "plug and play" interconnection process for the distribution system. The value of the Commission's proposed pilots in paving the way for these objectives is also dependent on accurate, real-world validation of distribution system modeling.

Enphase is currently collaborating with Sandia to compare OpenDSS feeder models to actual real-world measurements taken by smart inverters, as well as with the State of Hawaii on

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[4] Id.

[5] The error rate must be made public to stakeholders. If the error rate is larger than a pre-determined acceptable limit, utilities must be required to collect more data from DER systems in order to refine their power flow models.

resolving grid reliability challenges through circuit level analysis of historical data at the feeder level, allowing for a higher granularity of system visibility and resulting in highly cost-effective DER upgrades. With over 75,000 systems in California, and over 30,000 in Hawaii, we can provide significant assistance to the Commission, as can many other market participants who have significant data to offer to these important analyses. The value of this information to establishing "a roadmap for integrating cost-effective DERs into the planning and operations of IOUs' electric distribution systems with the goal of yielding net benefits to ratepayers"[6] should not be underestimated, and should not be ignored in the DRPs that the Commission ultimately approves.

IV. CONTROL SYSTEMS SHOULD BE RECOGNIZED AS INDEPENDENT DERS AND INCLUDED IN THE DER PILOT

The value of DERs will substantially depend on their visibility to the distribution system operator as well as the extent to which their ability to provide energy and energy services can be controlled to better meet power and reliability needs. Sensor, communication, and management systems (collectively, "DER Control Systems"), whether provided by DER generation, storage, demand response, energy efficiency, the distribution system operator or, as is already often the case, independent DER Control System entities, have an exceptionally important role to play in the reliable, cost-effective operation of the distribution system— and in its ability to host increasing amounts of DER elements. The Commission should include DER Control Systems within the definition of DERs, and as separate from DER generation, storage, demand response or energy efficiency. Due to the pivotal importance to DER reliability and cost, the value of differing sensor, communications and control systems should be explicitly tested in the Commission's proposed first DER pilot.

One example of the potential benefits of DRP Control Systems is the dynamic control of smart inverter functions which can have a substantial impact on increasing hosting capacity—in addition to providing locational benefits. Again, real-world validation of the modeled behavior needs to be compared with measured reality; equipping feeders to be fully equipped with control capabilities in the pilot areas would be particularly valuable. By incorporating DRP Control Systems explicitly into the Commission's pilots, the Commission can establish the extent to which

[6] Order Instituting Rulemaking Regarding Policies, Procedures and Rules for Development of Distribution Resources Plans Pursuant to Public Utilities Code Section 769 (Aug. 20, 2014) at p. 4.

active control provides additional capacity and energy service benefits, including locational benefits. The capability of DRP Control Systems to defer or eliminate the need for distribution system upgrades, to support establishment of DER zones and to enable "plug and play" interconnection and integration of DER elements merits their explicit definition as a separate DER and their explicit assessment in the Commission's pilots.

V. CONCLUSION

The Commission is on an exemplary path forward to maximizing the value of increasing participation of DERs in our energy system. To achieve the Commission's objectives, a clear understanding of the existing distribution system, of the costs and benefits of adding varying DERs to it, and of any proposed upgrades to the distribution system to enable DER zones and "plug and play" interconnection of DERs is essential. This can only occur by ensuring accurate modeling through tailored power flow analyses using actual DER data—including validation of that modeling against existing data and the data to be drawn from the proposed pilots. Data sharing issues must be addressed, including adequate protection of privacy as well as adequate compensation for the value provided, but these should be addressed in a separate track. Minimum standards for reactive power monitoring and control from all future DER systems installed, consistent with those being addressed in the Rule 21 proceeding, should be required. DRP Control Systems will undoubtedly be pivotal in determining the capacity of distribution systems to absorb DER elements, and to both reduce the costs and increase the reliability of the distribution system as DERs are added. An explicit, and separate, definition of DRP Control Systems and inclusion of DRP Control Systems within the meaning of DERs, would therefore provide significant value towards achieving the Commission's goals for DRPs.

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Respectfully Submitted,

By:

/s/ Arthur L. Haubenstock______________

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DATED: December 15, 2014

ATTACHMENT

Using Hosting Capacity Methodology to Develop Simplified Screens for New Solar PV Interconnections

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EPRI

Robert Broderick
Sandia National Laboratory

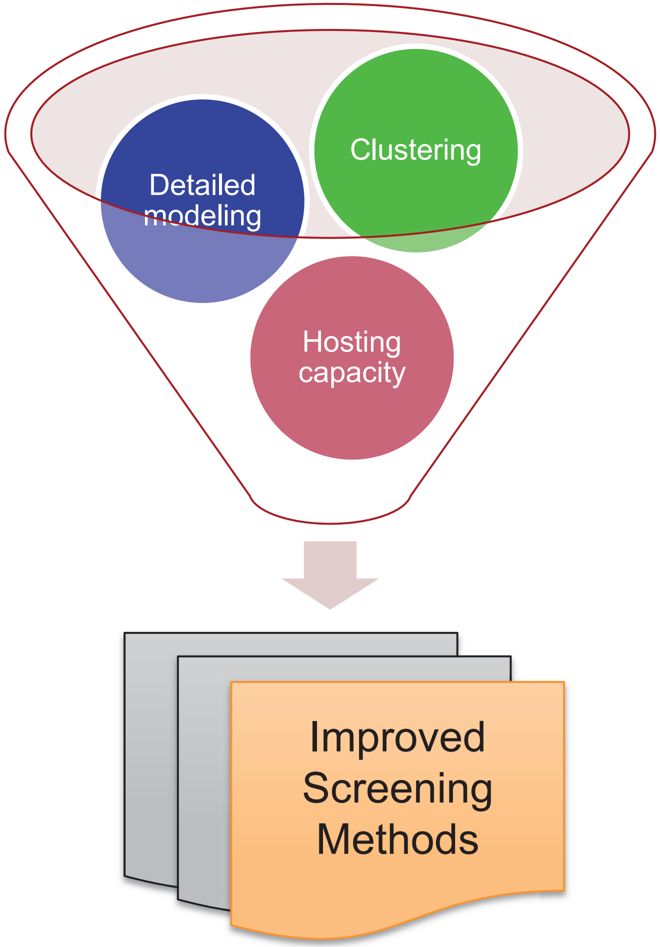
Barry Mather
NREL

6th International Conference on Integration of Renewables and DER
Kyoto, Japan
11/18/2014

Developing New Screening Methods

CPUC/EPRI/DOE Project

- Objective
  - Develop improved screen that streamlines process without over/underestimating PV impacts
- Approach
  - Characterize 8000+ feeders in California for
  - Clustering analysis to select 15 feeders
  - Perform detailed hosting capacity assessments to determine range of impacts and issues
  - Develop improved screens
  - Modeling and field validation
- Project Team
  - EPRI, Sandia, NREL, PG&E, SDG&E, SCE, ITRON
- Ongoing effort
  - Results available 2014/2015

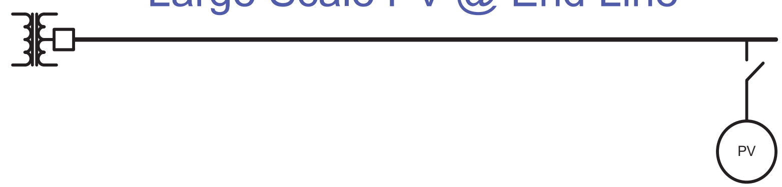


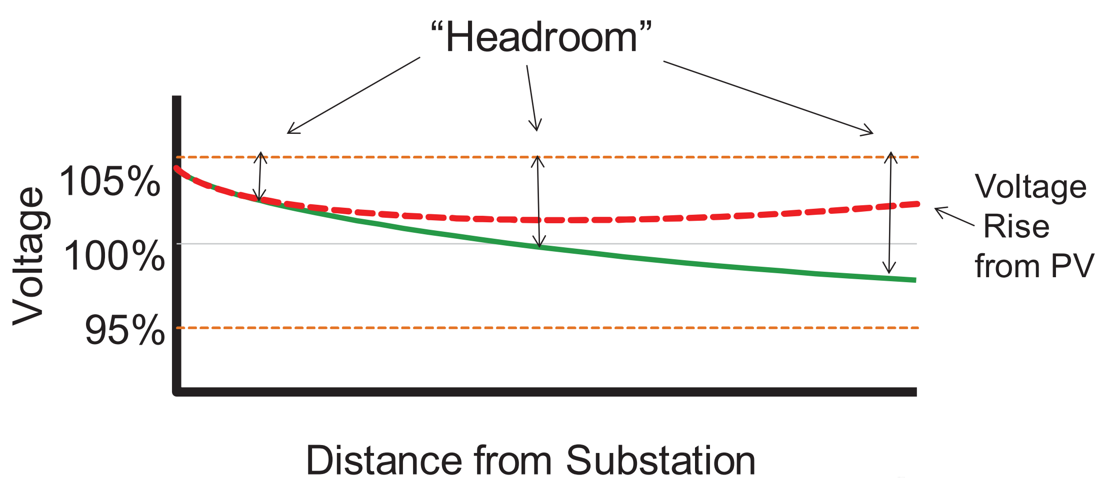
Key Factors that Determine Hosting Capacity

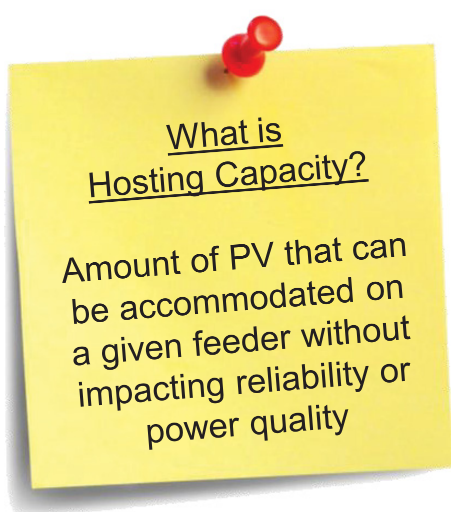
- **Size** of PV
- **Location** of PV
- **Feeder** characteristics
- Electrical proximity to other PV
- PV control (e.g, smart inverters)

Large Scale PV Near Sub

Large Scale PV @ End Line







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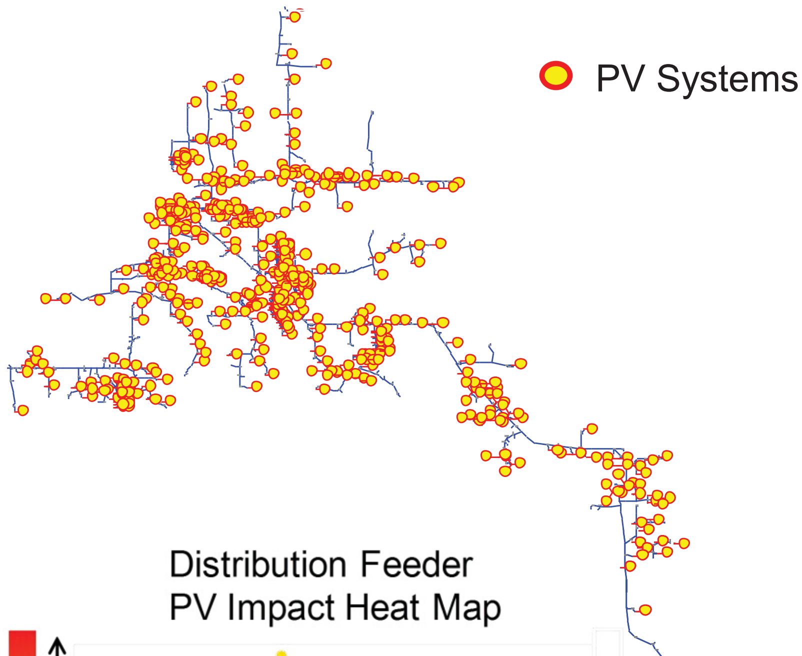
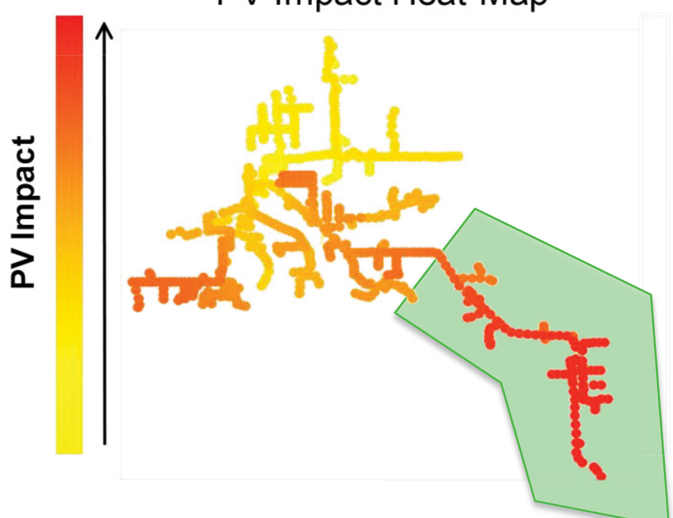
Feeder Hosting Capacity: A Brief Primer



Distribution Feeder
PV Impact Heat Map



Baseline – No PV

PV Penetration 1

PV Penetration 2

PV Penetration 3

Beyond…

Process is repeated 100's of times to capture many possible scenarios

Increase Penetration Levels Until Violations Occur

- voltage
- protection
- power quality
- thermal

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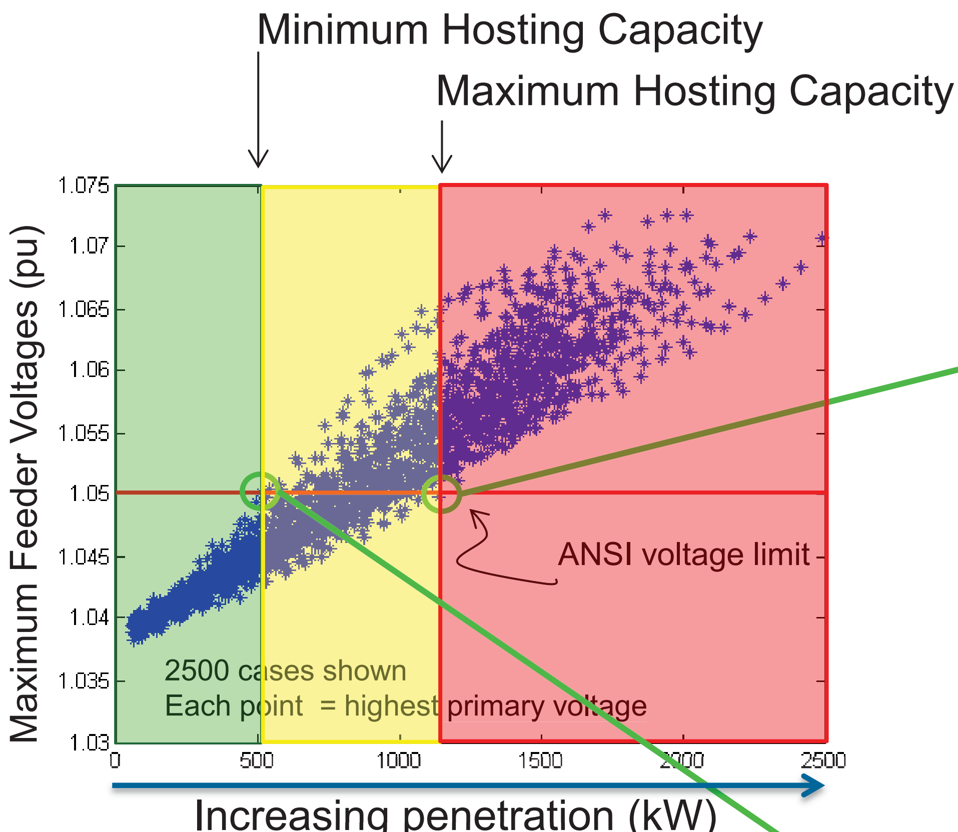
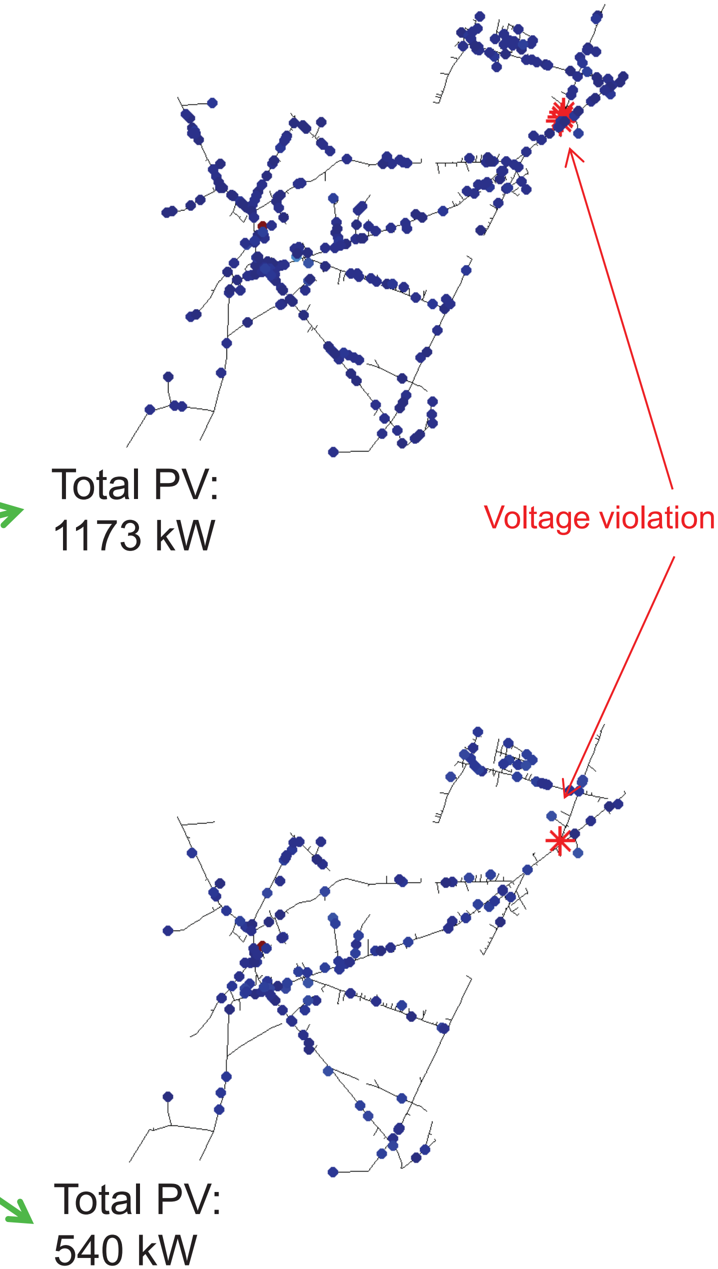
Hosting Capacity

Illustration of Overvoltage Results





No observable violations regardless of size/location

Possible violations based upon size/location

Observable violations occur regardless of size/location

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Hosting Capacity Response Thresholds

Category	Criteria	Basis	Flag
Voltage	Overvoltage	Feeder voltage	≥ 1.05 Vpu
	Voltage Deviation	Deviation in voltage from no PV to full PV	≥ 3% at primary ≥ 5% at secondary ≥ ½ band at regulators
	Unbalance	Phase voltage deviation from average	≥ 3% of phase voltage
Loading	Thermal	Element loading	≥ 100% normal rating
Protection	Element Fault Current	Deviation in fault current at each sectionalizing device	≥ 10% increase
	Sympathetic Breaker Tripping	Breaker zero sequence current due to an upstream fault	≥ 150A
	Breaker Reduction of Reach	Deviation in breaker fault current for feeder faults	≥ 10% decrease
	Breaker/Fuse Coordination	Fault current increase at fuse relative to change in breaker fault current	≥ 100A increase
Harmonics	Individual Harmonics	Harmonic magnitude	≥ 3%
	THDv	Total harmonic voltage distortion	≥ 5%

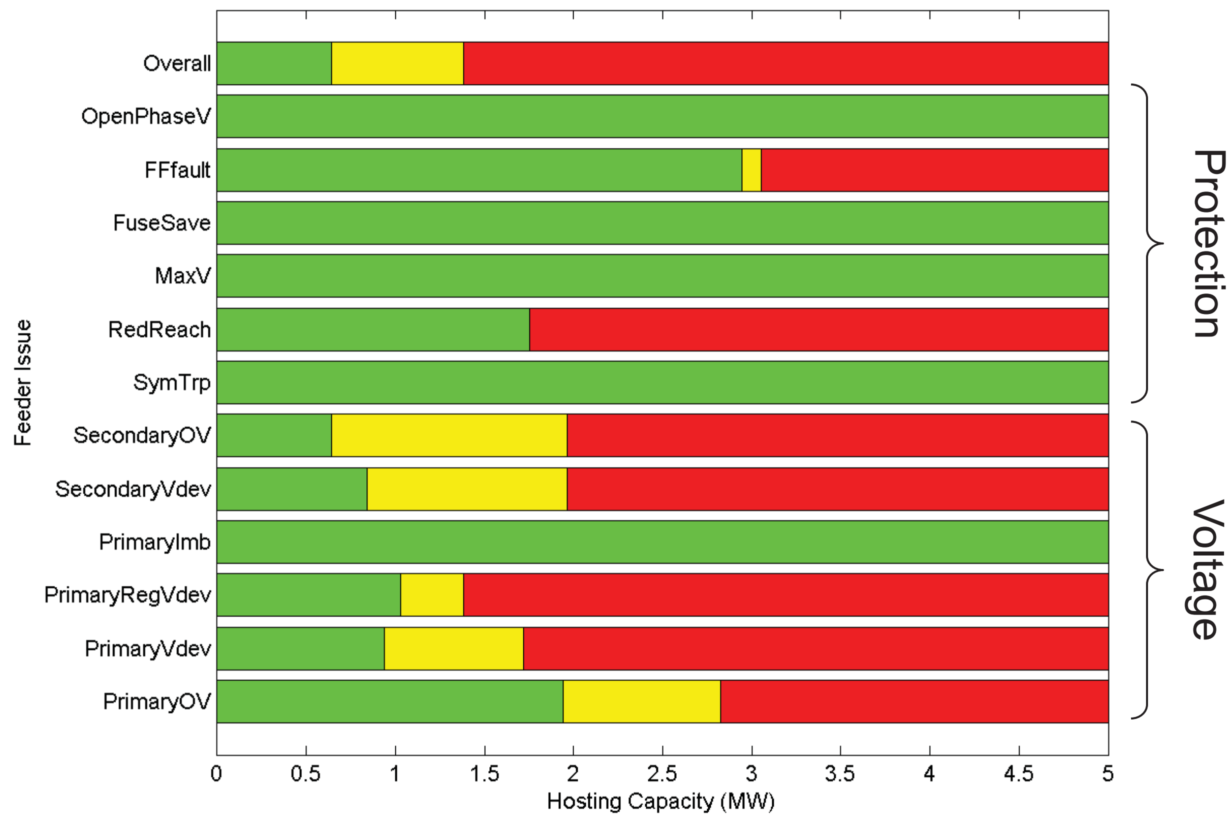
Sample Results from Single feeder

Small-Scale (Residential/Commercial)

Feeder Characteristics

Characteristic	Value
kV	12
Pk Ld	6.2
Min Ld	0.62
Total Regs	1
Setpoint	1.0
Band	4.0
Total Caps	1
Total kvar	1200
End of Line Z	15.88
Avg Z	5.86
Min Z	1.11
Max XR	7.87
Avg XR	2.52
Min XR	0.70
Total Miles	71.87
Total CustCount	1140.00
End of Line Length (mi)	11.07
Avg R	2.16
End of Line MVA	9.10
Min Headrom	0.03
Load Center R	5.90

Hosting Capacity Results



Feeder 2885

Simulations results from OpenDSS

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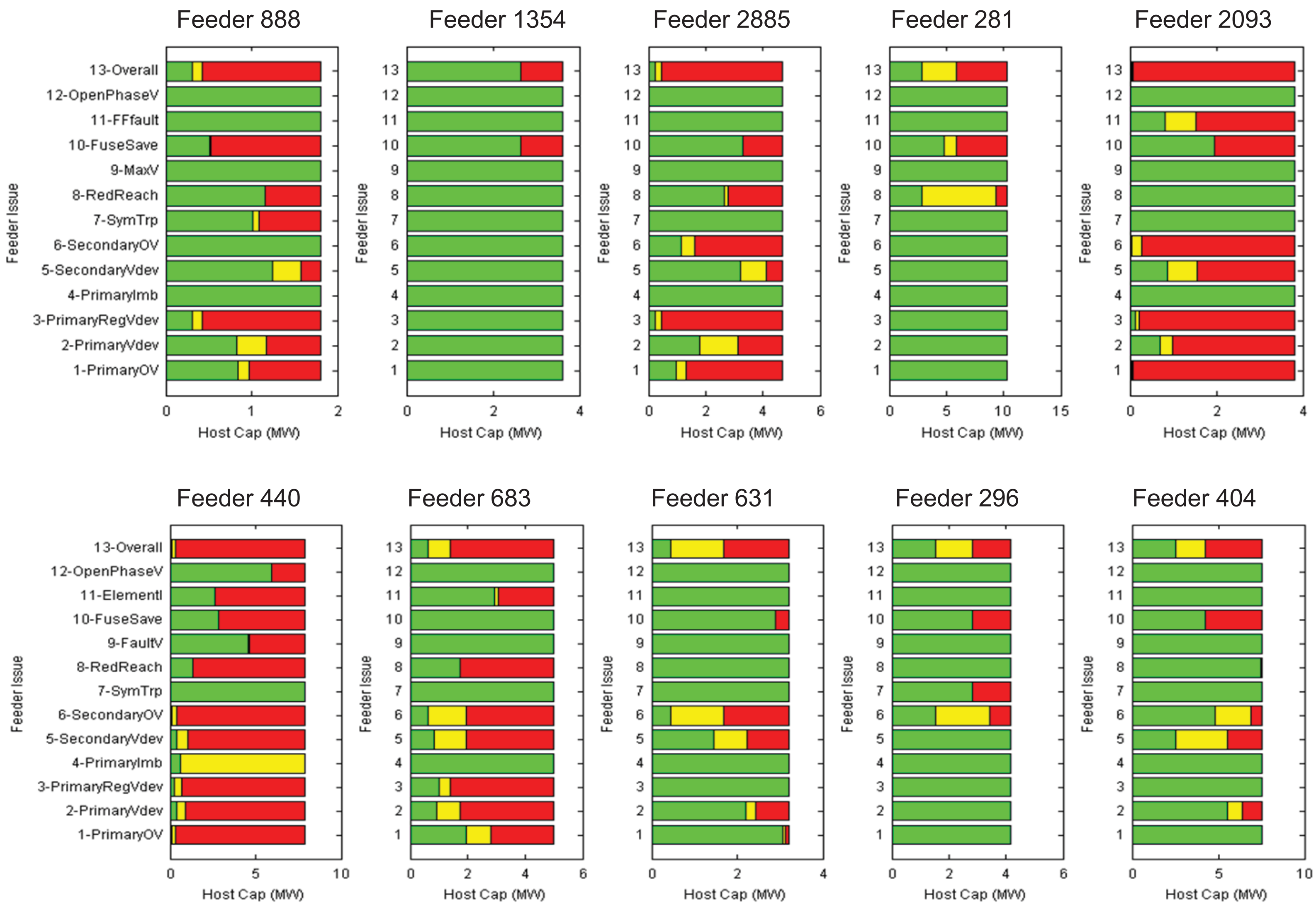
Residential/Commercial Rooftop PV

Overview of Results from 10 California Feeders



PG&E

SDG&E

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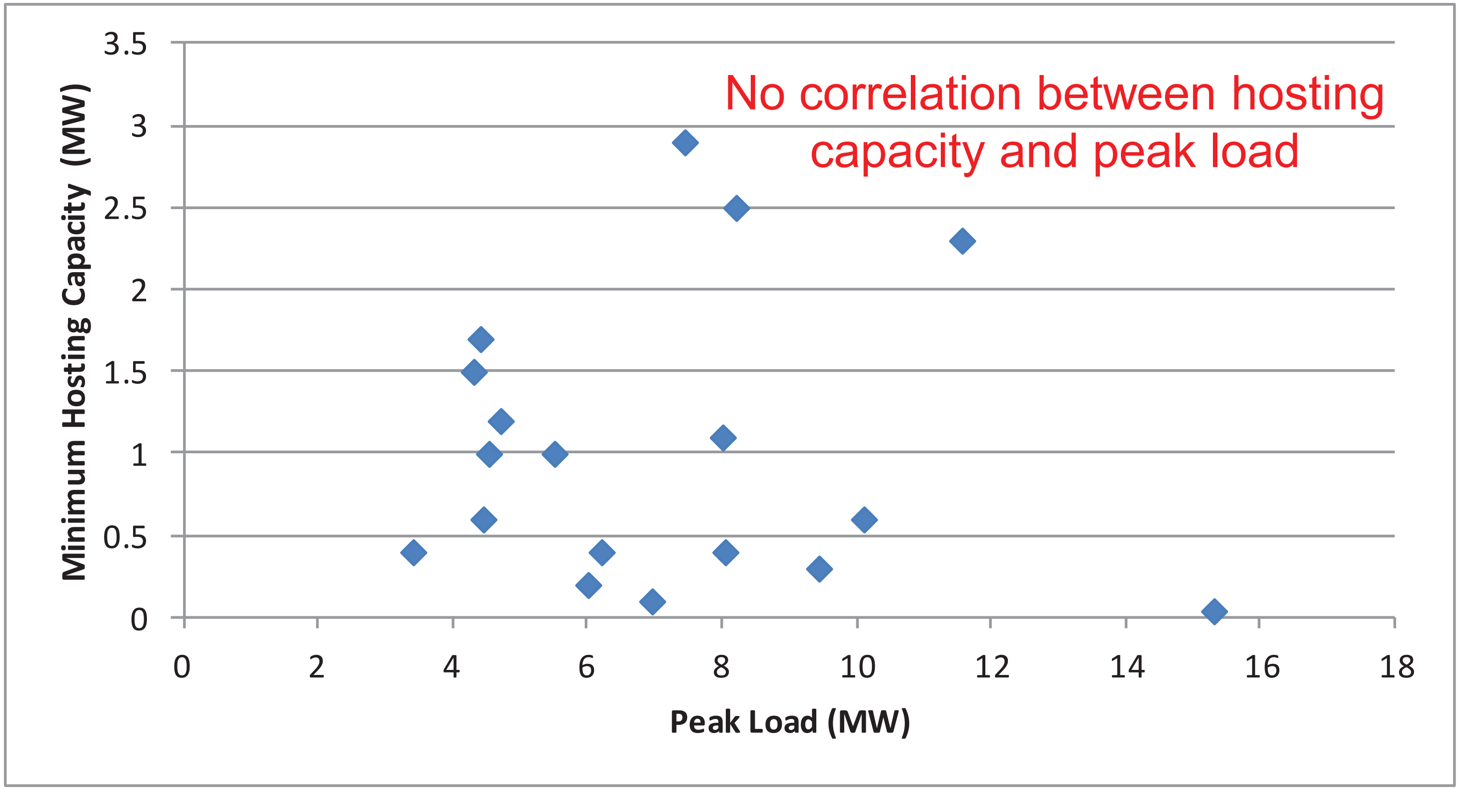
Detailed Hosting Capacity Analysis

Question: Can load be used to predict hosting capacity?

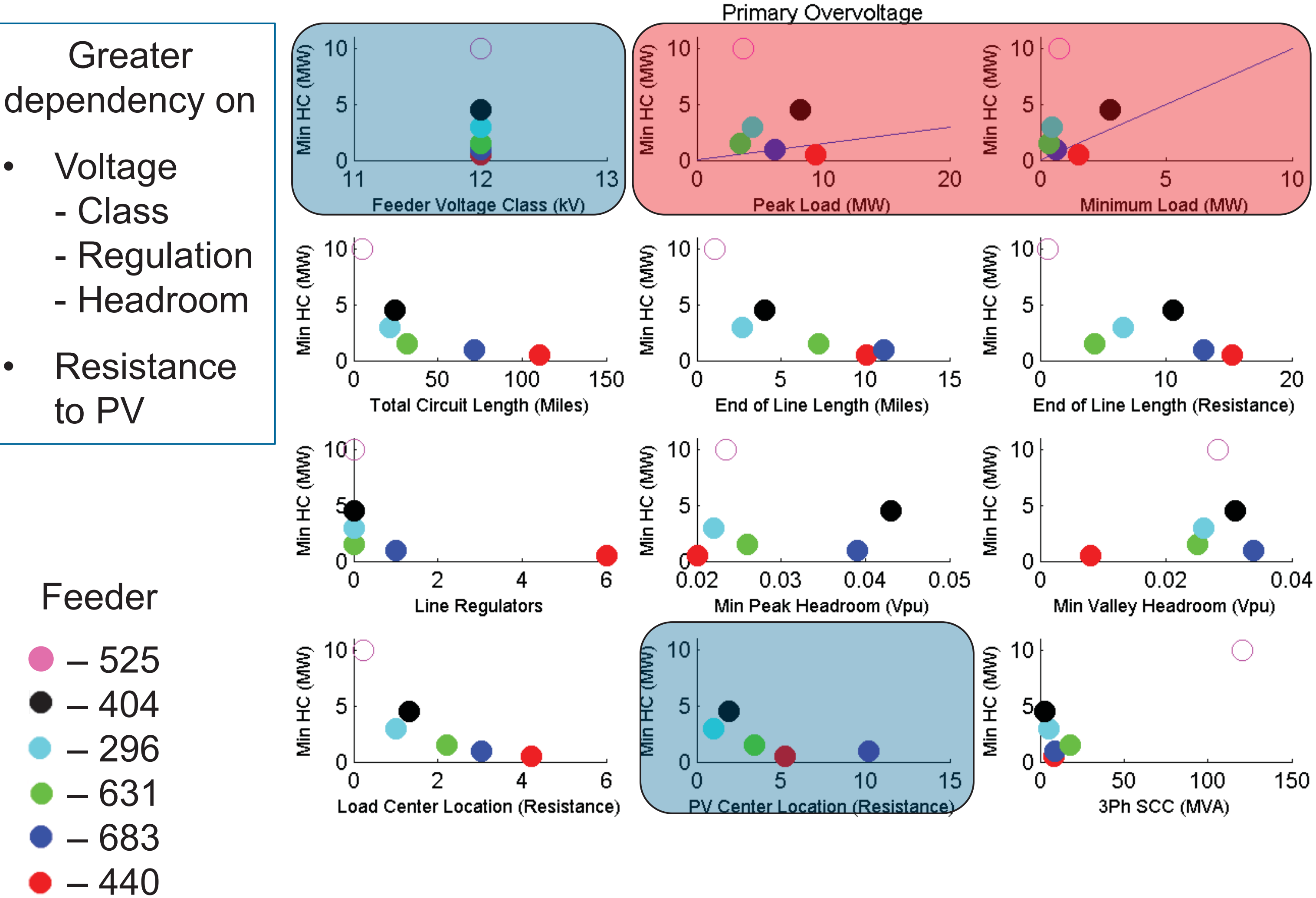


Answer: Not without knowledge of other feeder characteristics

Characteristics Correlated to Minimum Hosting Capacity for Primary Overvoltage

Greater dependency on

- Voltage
  - Class
  - Regulation
  - Headroom
- Resistance to PV



Percent of load screens over/under estimate hosting capacity

Summary

- Alternative screening methods are needed
- Improved methods can be developed that <u>efficiently</u> and <u>effectively</u> screen new interconnection requests
- From the trends in hosting capacity results, new screening techniques can be developed
- Improved screening likely to be based upon
  - Topological data
    - Static data (voltage class/regulation approach, end of line length, total feeder length, etc.), and/or
  - Feeder response
    - Voltage and protection response
    - Using commercial tools (CYME, SynerGEE, Milsoft, etc)
- Next steps

Project Team

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Sandia National Laboratories

NREL

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Questions

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